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Hydropower Investment Promotion Project (HIPP)

REGIONAL ELECTRICITY MARKET REVIEW

August 2013

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Acronym	Term
B2B	Back to Back
ESCO	Electricity System Commercial Operator
GNERC	Georgian National Energy and Water Supply Regulatory Commission
GSE	Georgian State Electrosystem
HPP	Hydro Power Plant
IAEA	International Atomic Energy Agency
MCM	Thousand cubic meters
MIE	Ministry of Industry and Energy of Azerbaijan
MOE	Ministry of Energy of Georgia
MINENERGO	Ministry of Energy of Russia
NPP	Nuclear Power Plant
O&M	Operations and Maintenance
PSRC	Public Services Regulatory Commission of the Republic of Armenia
PV	Photovoltaic
R2E2	Renewable Resources and Energy Efficiency Fund
RE 2008	2008 Resolution on Renewable Energy
RES	Renewable Energy Sources
SS	Substation
TEIAS	Turkish Electricity Transmission Company
TETAS	Turkish Electricity Trade and Contract Corporation
TPP	Thermal Power Plant

1 INTRODUCTION

USAID's Hydropower Investment Promotion Project's main objective is to attract public and private investment in Georgian small and medium-sized run-of-river hydropower plants. As part of the project, HIPP is tasked to:

1) Review and assess regional electricity markets;
2) Identify competition to new Georgian HPPs; and,
3) Analyze the potential for trade between Georgia and the various regional electricity markets.

This report summarizes the information gathered by HIPP over the last 3 years and provides an update on the latest information available on these three issues. This report is offered in three sections:

- Individual Country Analysis
- Competition to New Georgian Run-Of-River HPP Projects
- Regional Trading Opportunities

2 INDIVIDUAL COUNTRY ANALYSIS

This section of the report provides an overview of the electricity markets of individual countries in the Caucasus region and Turkey. The section highlights historical, current and projected generation and consumption, and each country's interconnections with their neighbors. The following five countries are examined: Armenia, Azerbaijan, Georgia, Turkey and Russia.

2.1 ARMENIA

DEMAND FOR ELECTRICITY

Electricity demand in Armenia has increased by an annual average of 3.3% from 2008. For the year 2012, total consumption of the country was 5.12 TWh. During 2012, industry consumed approximately 23% of total electricity of Armenia, the residential sector consumed 37%, transportation consumption was 2% and the commercial and public sector consumption was 38%. Peak demand has shown an increasing trend from 2008 (see Table 2.1.)

Table 2.1 Peak Domestic Demand and Energy (without/with losses) of Armenia; Historical data

	Peak MW	Energy GWh
2008	1204	4729.7 / 5493
2009	1062	4378.8 / 5090
2010	1053	4507.7 / 5213
2011	1251	4869.7 / 5637
2012	1322	5119.5 / 5923

Sources: PSRC (www.rsrc.am), Settlement Center

GENERATION RESOURSES

Armenia's electricity system has over 3,390 MW of installed capacity. Currently, only 66 percent is operational (2,550 MW). Of the total installed capacity, 53 percent is thermal, 34 percent is hydro and 12 percent is nuclear. Armenia also has a small wind power plant with 2.6 MW installed capacity.[1]

Electricity production in 2012 was 8 TWh, of which 29% was provided from nuclear, 29% by hydro and 42% by thermal. Thermal generation relies entirely on imported natural gas from Russia and Iran.

The shares of thermal and hydropower plants in the capacity and generation have increased in recent years as several new plants have been built.

Table 2.2 Generation Resources of Armenia, 2012

Generation Resources	Capacity [MW]	Annual Generation [MWh]
Hydro	1 052	2351.3
Thermal	1 931	3374
Nuclear	408	2311
Wind	2.6	
Other Renewables		
TOTAL	3 394	8036.3

Source: PSRC

The Armenian nuclear power plant provides base load capacity while the thermal power plants typically operate to meet peak demand during winter period. But the thermal power plants can also be run as base load plants when the nuclear power plant goes offline for maintenance; hydropower plants provide daily load variations, but have lack of operable capacity during winter months.

More than 50% of the thermal power generating units in Armenia are old and they need refurbishment. Many of the thermal power plants were built in 1970s and are in poor operating conditions. The nuclear power plant is one of a few remaining nuclear power reactors in the world that was built without primary containment structures. It is regarded by international nuclear regulatory agencies as inherently unsafe and is scheduled to decommission in 2021. The Government of Armenia is considering a 10 years life extension for the NPP.

EXISTING TRANSMISSION INTERCONNECTION

Armenia has high voltage interconnections with all neighbors: Iran, Turkey, Azerbaijan, and Georgia. However, the lines going to Turkey and Azerbaijan are currently not in operation for political reasons. There are no plans for energy trade between Armenia and these two countries. The existing transmission network of Armenia is shown in Table 2.3 below.

[1]Public Services Regulatory Commission of the Republic of Armenia (www.psrc.am)

Table 2.3 Armenian International Interconnections

Country	Type of Connection	Maximum Capacity (MW)	Current Status
Azerbaijan	One line 330 kV (107 km)	420	out of use
	One line 220 kV		
	Two lines 110 kV		
Georgia	One line 220 kV (65 km)	250	operational
	Two lines 110 kV		
Turkey	One line 220 kV (65 km)	300	out of use
Iran	Two lines 220 kV (78.5 km)	400	operational

FUTURE GENERATING FACILITIES

Armenia's energy strategy emphasizes development of indigenous resources and with priority given to renewable energy production. Thus, the country is planning to diversify its electricity generation by using renewable resources. It is estimated that Armenia has more than 1,000 MW of technically viable capacity from solar photovoltaic (PV), 300-500 MW from wind, 250-350 MW from unexploited small HPPs, and 25 MW from geothermal. There is also potential for producing roughly 100,000 tons per year of biofuel from local plants.[2]

According to the Armenian Renewable Energy Roadmap project[3], the contribution of the renewables in Armenia can be increased by 2020. In 2012 renewable energy production generated 310 GWh, and it is forecasted to generate 740 GWh in 2015 and 1500 GWh by 2020.

The Government of Armenia was planning to build a new nuclear power plant with 1,000 MW of installed capacity. It was scheduled to become operational in 2021 and would replace Metzamor NPP, which has been scheduled for decommissioning by 2021. Armenia needs significant new investments in order to maintain necessary generation capacity reserve. The new NPP project was eliminated from the Government's Energy Program for 2013-2017. Table 2.4 below presents the summary of main investment projects in Armenia.

Table 2.4 Investment Projects in Armenia

Technology Type	Installed Capacity (MW)	Annual Generation (million kWh)	Expected Implementation Date
Small HPPS (<10 MW)	260	600	2025
Medium Size HPPs	275 - 300	1300 – 1400	2015
Wind farms	200	525	2025
TOTAL	735 -760	2425 – 2525	

Source: Armenian Energy Sector Overview, Energy Strategy Center.

[2] *Armenia Renewable Resources and Energy Efficiency Fund (R2E2)*

[3] http://r2e2.am/wp-content/uploads/2012/07/Renewable-Energy-Roadmap-for-Armenia.pdf

FUTURE CONSUMPTION

The demand for electricity in Armenia is expected to increase in the coming years. The Ministry of Energy of Armenia with the help of USAID in 2010 developed a demand forecast. The MoE forecasts electricity growth at 2.7% between 2010 and 2020, on average.

Under these conditions, in 2015, the peak load is estimated to be about 1350 MW and 1540 MW by 2020. Estimated energy and peak demands for the planning period are given in the table below.

Table 2.5 Armenia Projected Peak Domestic Demand and Energy (without plants self-consumption and with losses)

	Peak (MW)	Energy (GWh)
2015	1350	6150
2020	1540	7000

Source: Technical Report. Phase 1.USAID funded project "Assistance to Energy Sector to Strengthen Energy Security and Regional Integration", TetraTech, 2010, www.armesri.am

Taking into account last year's results (Table 2.1), the projected peak and energy growth rates may be viewed as optimistic.

2.2 AZERBAIJAN

DEMAND FOR ELECTRICITY

Consumption of electricity in Azerbaijan steadily grew from 1997–2006. In 2007 the increasing trend reversed and started to decline until 2010. The main reasons for the fall were the retail tariff increase in January 2007, implementation of government's policy to install meters and increased bill collection. A further factor was the gasification program, which allowed the switching from electricity to natural gas for heating. In 2011, electricity consumption showed increased trend again (by 8%) and reached 13.4 TWh.[4]

According to Azerenerji, the demand for electricity is expected to double between 2012 and 2022, and to increase by almost 140% by 2025. The peak demand is also expected to double by 2022–2023.

Table 2.6 Peak Demand and Energy of Azerbaijan; Historical data

	Peak MW	Energy GWh	Annual Change (%)
2008	-	15,650	-
2009	-	12,393	-21%
2010	-	12,326	-1%
2011	-	13,369	8%

Source: MIE, 2012

[4] Source: Ministry of Industry and Energy of Azerbaijan

GENERATION RESOURSES

Electricity generation in Azerbaijan is based on natural gas, heavy oil (during peak demand) and hydropower. The country is using its natural gas resources increasingly for power generation. After 2009, the share of oil products in electricity generation was entirely replaced by natural gas.

According to the 2013 statistics of Azerenerji, 13 thermal and eight hydro power plants are in operation. Total installed generation capacity is 6,315 MW, of which thermal power stations contribute 5,253 MW (83%) and hydropower stations make up the balance.

Electricity generation of the country increased annually an average of 4% from 1997. In 2011 total generation was 20,294 TWh. The share of thermal energy production of total generation was 87% and the share of hydro production was 13%.

Table 2.7 Generation Resources

Generation Resources	Installed Capacity [MW]	Annual Generation [GWh]
Hydro	1,063	2,676
Thermal	5,253	17,618
Nuclear	-	-
Wind	-	-
Other Renewables	-	-
TOTAL	6,316	20,294

Source: Azerenerji; MIE

EXISTING TRANSMISSION INTERCONNECTIONS

Azerbaijan currently has the following interconnections with its neighbors:

Table 2.8 Azerbaijan Interconnections

Country	Type of Connection	Maximum Capacity (MW)	Current Status of Line
Armenia	One line 330 kV	420	not operational
	One line 220 kV		not operational
	Two lines 110 kV		not operational
Georgia	One line 500 kV	850	operational
	One line 330 kV	250	operational
Russia	One 330 kV	500	operational
Iran	Two lines 154 kV (to Nakhichevan)		operational
	Two lines 132 kV		operational
Turkey	One line 150 kV	100	operational
	Two lines 220 -230 kV via Iran	40	operational

Source: ECON Poyry Study for the Caucasus Region, 2009

Although interconnection lines between Azerbaijan and Armenia do exist, no power exchange takes place due to their political dispute since 1989. There are no plans for resumption of energy trade between the two countries.

FUTURE CONSUMPTION

The government of Azerbaijan produced a demand and peak load forecast in 2007. The demand on electricity is expected to double between 2012 and 2022, and to increase by almost 140% by 2025. The peak demand is also expected to double by 2022–2023. Forecasted peak load and electricity consumption are shown below.

Table 2.9 Estimated Peak Demand and Energy of Azerbaijan

	Peak (GW)	Energy (TWh)	Change (%)
2015	4.7	24	5.5%
2020	6.3	32	4.7%
2025	8.2	39	4.7%

Source: Energy Charter, Energy Efficiency of Azerbaijan 2013.

FUTURE GENERATING FACILITIES

Azerbaijan has large potential resources for several types of renewables: hydro, solar, wind, geothermal and biomass. There are significant agricultural operations in the country that could provide residues for biomass combustion or gasification. There also exists solar and wind energy potential due to favorable climatic conditions. The country is also rich with geothermal power.

The development of small HPPs is one of the main components in the RES sector. Although the country currently does not utilize all of its RES, the development of RES is also one of the government's strategic priorities.

By the end of 2015, total generating capacity will increase by 30 percent according to Azerenerji with three new thermal projects and 25 small hydro power plants are under construction with the total 1815 MW of installed capacity.

2.3 GEORGIA

DEMAND FOR ELECTRICITY

The demand for electricity in Georgia has increased by an average 4% per annum since 2007 including a 10% rise between 2010 and 2011[5], driven by a two-fold increase of GDP 2007 to 2011)[6].

For the year 2012 total consumption of the country was 9.4 TWh (increased by 1%). The greatest demand for electricity is during winter months as a big share of the consumed power (up to 30%[7]) falls on the residential sector, which uses electricity for heating in winter months.

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[5] ESCO, Energy Balances of Georgia

[6] National Statistics Office of Georgia

[7] Source: GNERC

Table 2.10 Peak Demand and Energy of Georgia; Historical data

	Peak MW	Energy GWh
2008	1580	8074.8
2009	1538	7642.1
2010	1620	8441.1
2011	1681	9256.6
2012	1680	9379.4

Source: Georgian State Electrosystem (GSE); ESCO

GENERATION RESOURSES

Total installed generation capacity in Georgia is over 3,300 MW. Approximately 80% of installed capacity is provided by renewables (hydro-generation). The table below shows distribution of country's generating resources.

Table 2.11 Generation Resources of Georgia

Generation Resources	Capacity [MW]	Annual Generation [MWh]
Hydro	2,624	7,221
Thermal	693	2,477
Nuclear	-	-
Wind	-	-
Other Renewables	-	-
TOTAL	3,317	9,698

Source: ESCO, Electricity balance of Georgia 2012

In 2012 the gross electricity generation in Georgia was 9.7 TWh. The share of hydro in total generation was 74% and share of thermal production – accordingly as 24%. The market shares of the three largest generators made: Enguri HPP Ltd. – 33%; Mtkvari Energetika Ltd. – 12%; Vardnili HPP Cascade Ltd. – 6%.

Currently, thermal power producers (TTPs) normally generate electricity from September to April, accounting for 20% of the total installed capacity of the system. Georgian generation is quite seasonal particularly, the run-of-river HPPs. The amount of hydropower generated energy available is determined by rain or snow fall in each plant's hydrological basin. The capacity issue with run-of-river is that with no, or only small, dams or reservoirs to store water, the power plants rely on seasonal availability of water. This leads to diversion of excess water during spring and early summer periods and almost no power generation during drought conditions. This results in Georgia typically having to import energy during the winter period.

EXISTING TRANSMISSION INTERCONNECTION

Georgia currently has the following interconnections with its neighbors:

Table 2.12 Georgian International Interconnections

Country	Type of Connection	Maximum Capacity (MW)	Current Status of Line
Armenia	220 kV	180 MW	operational
	110 kV	30 MW	from 2013
	110 kV	20 MW	from 2013
Azerbaijan	500 kV	850 MW	from 2013
	330 kV	250 MW	operational
	220/110 kV	230 MW	operational
Russia	500 kV	850 MW	operational
	220 kV	100 MW	operational
	110 kV	30 MW	operational
	110 kV	30 MW	from 2013
Turkey	400 kV	700 MW	from 2013
	220 kV	120 MW	operational

Source: Georgian State Electrosystem

FUTURE GENERATING FACILITIES

One of the main directions of the energy policy of Georgia is to increase the share of renewables in total generated power and satisfy the demand for energy by its own resources of the country. The “State Program for Renewable Energy 2008” is still in force today. It offers investors a list of HPPs to be built in various regions of Georgia By the end of 2020, the share of energy produced from renewable energy is forecasted to increase by 7 percent as 40 new projects are being constructed (39 HPPs and one wind farm with 50 MW of design capacity) with 1879 MW of installed capacity and projected annual generation of 7410 GWh[8].

FUTURE CONSUMPTION

Note: There is no official projection for electricity demand in Georgia.

FUTURE TRANSMISSION FACILITIES

According to Georgian State Electrosystem, the country plans to build new transmission interconnections with its neighbors. The table below shows future projects of transmission facilities on the Georgia-Turkey and Georgia-Armenia borders.

Table 2.13 Perspective Transmission Projects of Georgia

Country	Type of Connection (kV)	Maximum Capacity (MW)
Turkey	200/154 kV(Batumi- Muratli)	350 MW
	400 kV(Akhaltsikhe -Tortum)	1050 MW
Armenia	500/400 kV (Marneruli-Alaverdi- Hrazdan)	

Source: Georgian State Electrosystem (GSE)

[8]Source: Ministry of Energy of Georgia

2.4 RUSSIA

DEMAND FOR ELECTRICITY

According to the data from Ministry of Energy of Russia (Minenergo), electricity consumption in 2012 as a whole amounted to 1 038.1 TWh which is 1.7% more than in 2011, but it is still below the 2000-08 average of 2.2%. The peak demand of 2012 amounted to 158,986 MW. According to an analysis framework of events "Energy of the Russian Federation", the number was recorded as the maximum load of Russia.

Table 2.14 Historical Electricity Demand in Russia

	Peak MW	Energy TWh	Annual Change (%)
2009	-	964.4	-4.6%
2010	-	1009.2	4.3%
2011	-	1021	1.2%
2012	158,986	1038.1	1.7%

Source: Minenergo

EXISTING GENERATION

In 2012, the total installed capacity in Russia increased by 6,134 MW (2.2%) and reached 223.1 GW. 68.1% of the installed capacity was thermal power plants, 20.6% was hydro power plants and nuclear power plants contributed the remaining 11.3%. The share of non-hydro renewable energy (geothermal and wind) accounted only about 1% of the total installed capacity[9].

Electricity production in 2012 was 1053.9 TWh which is 1.3% more than in 2011. 177.1 TWh (17%) came from nuclear power, 708.8 TWh from thermal (67%) and 168 TWh (16%) from hydro[10].

Table 2.15 Generation Resources of Russia, 2012

Generation Resources	Capacity [MW]	Annual Generation [TWh]
Hydro	46	168
Thermal	151.9	708.8
Nuclear	25.2	177.1
Wind	-	-
Other Renewables	2	
TOTAL	223.1	1053.9

Source: Minenergo

Russia's electricity supply faces a number of constraints. The first is obsolescence; Generating plants with capacity totaling 50 GW (more 25% of total capacity) are past the end of their design lives. Secondly, Gazprom is cutting back on level of natural gas supplies available for electricity production. Gas-fired plants use about 60% of the gas marketed and this level is scheduled to be halved by 2020.

EXISTING TRANSMISSION INTERCONNECTION

Five electrical interconnections connect Russia with its neighboring Caucasus countries. Characteristics of these connections are presented in the table below.

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[9]Press release on: “Power sector construction in Russia 2013. Development forecasts for 2013-2015.” June 2013.

[10]minenergo.gov.ru

Table 2.16 Russia Southern Region Interconnections

Country	Type of Connection	Maximum Capacity (MW)	Current Status of Line
Azerbaijan	330 kV	500 MW	operational
Georgia	500 kV	850 MW	operational
	220 kV	100 MW	operational
	110 kV	30 MW	operational
	110 kV	30 MW	operational

FUTURE CONSUMPTION

The “Energy Strategy of Russia” for the period up to 2030, adopted by the Russian Government in November 2009 projected that demand on electricity will grow in coming years. Annual power consumption growth rate was put at 4.5%. Demand on electricity is expected to reach 1,288 TWh in 2020 and 1,553 TWh in 2030 from 1,038 TWh in 2012.

The document also implies an increased need for import in the short run to meet domestic demand in Russia. The document emphasizes Ukraine and Kazakhstan as potential suppliers of electricity.

Table 2.17 Projected Energy Demand of Russia

	Peak MW	Energy TWh
2020	-	1288
2030	-	1553

Source: Energy Strategy of Russia for the period up to 2030

FUTURE GENERATION

In February 2010 the government approved the federal target program that envisages an increase of generation capacity at 355-445 GW in 2030. It requires construction of new power plants 78 GW of installed capacity by 2020 and total 173 GW - by 2030, including 43.4 GW nuclear. The plan also envisages decommissioning 67.7GW of capacity by 2030, including 16.5 GW of nuclear plant (about 7% of present capacity).

In July 2012 the Energy Ministry of Russia published a draft plan to commission 83 GW of new capacity by 2020, including 10 GW nuclear to total 30.5 GW producing 238 TWh. A year later Minenergo reduced the projection to 28.26 GW in 2019.

In parallel with this Russia is planning to increase hydro capacity by 60% to 2020 and double it by 2030.The aim is to have almost half of Russia's electricity from nuclear and hydro by 2030.

2.5 TURKEY

DEMAND FOR ELECTRICITY

Historically, energy consumption in Turkey has increased in proportion with the economic growth of the country. The demand on electricity has increased by an average of 8% per annum since 1960. It has been seen a 7% increase from 2001 to 2010, with much of the growth occurring between 2002 and 2008. Although demand fell in 2009 compared with the previous year because of the worldwide economic slowdown, in 2010 consumption increased by about 10% compared with the previous year. In 2011 total electricity consumption of the country was 229.3 TWh.

EXISTING GENERATION

Turkey has nearly doubled its installed power generating capacity in the last decade, reaching a total of 57,000 MW at the end of 2012. The highest share of the installed capacity in Turkey is thermal plants. As of 2012, 38% of total installed capacity is natural gas, 16% lignite, 2% fuel oil, 7% imported and hard coal, ca. 4% of installed capacity is wind, geothermal and other renewables; Share of hydro capacity is 33%.

In 2011 the electricity production in Turkey was approximately 228.4 TWh. 171TWh (74.8%) was based on thermal plants and the remainder 58 TWh (25.2%) was produced by renewable sources such as hydro, geothermal and wind.

An analysis of power generation reveals the increasing importance of natural gas. In 2011, 44.7%, 28.3%, and 22.8% of total production was based on natural gas, coal and hydro respectively while the shares of oil derivatives and wind were 1.7% and 2.1%[11].

EXISTING TRANSMISSION INTERCONNECTION

Turkey has the following high-voltage transmission interconnections:

Table 2.18 Turkey Interconnections:

Country	Type of Connection	Maximum Capacity (MW)	Current Status
Armenia	One line 220 kV (78.5 km)	300	out of use
Azerbaijan	One line 154 kV (87.3 + km)	100	operational
	One line 34.5 kV (44.5 km)	40	operational
Georgia	One line 220 kV (28 km)	300	operational
	One 500 kV		
Bulgaria	One line 380 kV (136 km)	500	operational
Iran	One line 154 kV (73 km)	100	
Iraq	One line 380 kV (16+ km)	500	out of use
Syria	One line 66 kV (7.5+ km)	40	operational

FUTURE CONSUMPTION IN TURKEY

According to TEIAS projections, the electricity demand will reach between 398 to 434 TWh by 2020 depending on the low or high growth scenarios. The capacity should be at least 61-67 GW in order to meet such a huge growth in demand (TEIAS, 2012). Taking into consideration the required capacity additions, the maintenance-expansion requirements in grid infrastructure as well as the privatization process, potential investors face a free and competitive market with tremendous investment opportunities.

[11] TEIAS, 2012

3 Competition to new Georgian Run-of-River HPP projects

According to the Government of Georgia's 2008 Resolution on Renewable Energy (RE 2008), new Georgian run-of-river projects are not afforded a feed-in tariff by the Government of Georgia. Rather, in theory, new HPPs are to sell their electricity output into the competitive Georgian electricity market for three months of every winter season (for ten years after commercial operation) and into the competitive regional electricity market for the rest of year and for all seasons after 10 years. In practice though, ESCO provides a feed-in tariff formula based on the average cost of generation from thermal power plants for at least three months of the winter season and sometimes many more months. ESCO's offer to provide a feed-in tariff blurs in reality what is the competition to new Georgian run-of-river projects.

3.1 Gas-fired Combined Cycles.

Georgia - Guaranteed Capacity (or Reserve Capacity as it is normally named). ESCO purchases capacity and energy from 3 power generating units at Gardabani power plant. ESCO pays the power plants for their capacity related costs and allocates these costs to the electricity sector entities. A sole-source offer from the Turkish firm, Calik, proposed to construct a 230 MW (net) natural gas-fired combined cycle at the Gardabani power plant. The offer also suggests that a 25-year power purchase agreement should be signed between Calik and ESCO.

In a truly competitive power market, there is no need for guaranteed capacity. The generation developers build capacity and produce electricity to meet the needs of the various markets including the hourly electricity balancing market and operating reserves market. If the TSO anticipates that there will be a shortage of capacity in the near future, then a tendering process for new generating capacity is completed and the cost allocated according to specific rules. That mechanism has yet to be developed in Georgia, and it creates confusion of whether the country will continue to develop thermal power plants or rely upon the market to determine how best to meet the energy and capacity needs of the country.

Certainly the new gas-fired generation (55-60% efficiency) at Gardabani, most likely having a take or pay natural gas contract, will provide electricity to the market in Georgia and Turkey, somewhere in the 5.5-6.5 cents/kwh range assuming the existing price of natural gas and a 70% annual plant factor.

Azerbaijan. Azerenerji operates on gas-fired combined cycle and plans to build additional combined cycles in the future. The price of natural gas in Azerbaijan is based on policies set by the Government of Azerbaijan. Gas prices for domestic electricity production are kept quite low. It is uncertain what natural gas price the government will set for electricity production for export. Due to the priority for new Georgian renewable power plants on the new transmission line to Turkey, electricity sales from new Georgian run-of-river HPPs will be protected from natural gas pricing policies in Azerbaijan.

Turkey. There are many existing gas-fired combined cycle plants operating in Turkey and many more are planned. These new plants are fired with natural gas coming mostly from Russia at a price of approximately $450/1000mcm. These plants set the market price for a majority of the hours during the year, therefore setting the benchmark for establishing contract prices for sales into Turkey from new Georgian HPPs. As long as the gas prices are stable or growing, these natural gas plants do not create a threat to Georgian HPPs, but a depression of gas prices, such as from a wide expansion of shale gas production, could have a material impact on the competitiveness of new Georgian run-of-river projects.

3.2 Large Reservoir HPPs.

Georgia. The Government of Georgia has aspirations for the construction of new large reservoirs by private investors in Georgian. Khudoni (702 MW) and Namakhavani (450 MW)are two examples of large reservoir HPP plants planned for development before 2020. The cost of construction for Namakhavani in the feasibility study funded by NUROL was in the range of $1.2 -$1.4 billion while the cost of Khudoni was estimated in a feasibility study funded by the World Bank to be approximately $1 billion. Not only will these projects put downward pressure on the market marginal price, they will also take up capacity allocation on the international interconnections, especially to Turkey.

Turkey. The GoT is building large reservoir projects on the Chorok River near the Georgian border. These include Borchka HPP (300 MW), Deriner (670 MW), Yusufeli (540 MW) and Artin (332 MW).

Azerbaijan. Azerenerji is constructing the 420 MW Tovuz HPP. Though the electricity production from the new HPP will stay in Azerbaijan, it will free up thermal power (fired by low-priced natural gas) which can compete against new Georgian HPPs.

3.3 New Nuclear Power Plant.

Armenia. For several years the Government of Armenia has promoted the idea of replacing Metsamor NPP with a new Russian-designed 1000 MW NPP. The plant’s capacity would exceed the country’s system demand for most of the year and its ability to cycle its operation would be quite limited. In other words, the new NPP would be built for domestic and regional electricity sales. The hourly amount of electricity sales in the off-peak periods, especially in the summer, could reach 800 MW from such a new NPP plant in Armenia. In the last five year energy strategy, 2013-2017, the Government of Armenia has removed all reference to a new NPP. It is not clear if consideration of the new NPP is now dead.

Turkey. The Government of Turkey has promoted the idea of construction of a large NPP station in Turkey. The Akkuyu Nuclear Power Plant is a planned nuclear plant at Akkuyu, in Büyükeceli, Mersin Province, Turkey. It would be the country's first nuclear power plant. In May 2010, the governments of Russia and Turkey signed an agreement that a subsidiary of Rosatom — Akkuyu NGS ElektrikUretim Corporation would build, own, and operate a power plant at Akkuyu comprising four 1,200 MW VVER units. The agreement was ratified by the Turkish Parliament in July 2010.Engineering and survey work started at the site in March 2011.The construction of the first unit will begin in 2014, with the four units put into service in 2019–22.49% stake will be sold to other investors.

> Turkish Electricity Trade and Contract Corporation (TETAS) has guaranteed the purchase of 70% power generated from the first two units and 30% from the third and fourth units over a 15-year power purchase agreement. Electricity will be purchased at a price of 12.35 US cents per kWh and the remaining power will be sold in the open market by the producer. In February 2013, Russian nuclear construction company Atomstroyexport (ASE) and Turkish construction company Ozdogu signed the site preparation contract for the proposed power plant. The contract includes excavation work at the site.

Source:NucNet, 22 February 2013.

3.4 New Coal-fired Power Plants.

Georgia. GIEC, a Georgian energy development and operating company, operates a small coal-fired power plant located near coal mines in central Georgia. The company is planning the construction and operation of two new 150 MW coal-fired power plants, one near their mine and one at the Gardabani power station. GIEC through its subsidiary, Saqnakhshiri, operates the Dzidziguri and Mendeli mines, located within the Tkibuli-Shaori coal basin. The company owns coal reserves of 331 million tons in the Tkibuli-Shaori region.

Turkey. Several new coal-fired plants, many of them along the Black Sea, are planned to be constructed in Turkey, some using local brown coal, some using imported hard coal. In either case, the production of electricity from new coal-fired power plants will be quite competitive with new run-of-river HPPs. There are several reasons, though, that the new coal-fired power plants are delayed and perhaps may even be canceled including: 1) meeting EU emission standards for large combustion plants, 2) local residents insisting on using local coal for creation of new jobs, and 3) international financial institutions, such as the IFC, deciding to distance themselves from with carbon-producing energy production.

3.5 Wind and Solar Power Projects.

Georgia. There are several potential projects in Georgia and the region for solar and wind farms. In fact small amounts of electricity are generated from these projects. The costs of wind power generation are between US¢ 9-11/kwh and solar powered production is between US¢ 12-15/kwh. Given the abundance of potential HPP projects with much lower cost of production, wind power and solar power projects will not most likely be built in large amounts for the planning horizon. That said, the price of wind and solar have dropped dramatically over the last 10 years and further drop in new facility costs could eventually make them competitive with new HPPs. With their low plant factor, 20-25%, and quite variable output makes them hard to compete in the competitive power market. Adding batteries to allow for better dispatch will only make their production costs higher.

Turkey. The Strategic Plan of Ministry of Energy and Natural Resources supports renewable energy targets for 2023, for example, 20 GW of new wind projects. These targets are supported with feed-in tariffs paid by the distribution companies. Solar and wind will therefore not compete in the competitive power market, but rather they will have the negative impacts for new Georgian run-of-river projects by lowering the competitive market prices (their production will lower gas electricity production at the margin) and perhaps creating congestion in the transmission network. Such large amounts of wind power will require significant additional thermal capacity and spinning reserve requirements to cover the variability of the production from the wind projects.

4 Regional Trading Opportunities

4.1 Georgia-Armenia electricity trade main options

Currently, the Georgian power system is synchronized with Russia and part of northern Armenia. The remaining part of Armenia's electricity network operates synchronously with Iran. The power systems of Russia and Iran can't be synchronized due to extensive operational coordination needed. So, technically there are two possible connections of power systems of Georgia and Armenia:

- Synchronously, when Georgia is disconnected from Russia or Armenia is disconnected from Iran;
- Asynchronously via a B2B (to be built).

The first option is cheaper, from the perspectives on not having additional transmission costs from B2B which is an expensive AC-DC-AC conversion.

4.1.1 Georgian and Armenian power systems synchronous operation

In the study completed by the USAID project "*Assistance to the Energy Sector to Strengthen Energy Security and Regional Integration*"[12], the options of synchronous operation of Armenian and Georgian power systems (excluding Iran) for 2015 and 2020 were developed. The options included new generation plants with renewable energy sources, Armenian electricity import capacity to replace the production of TPPs as well as export from Armenia to Georgia for own use and re-export to Turkey.

All calculations in the above analysis were carried out by hours using GTMax software. The calculated economic volume of electricity trade was relatively small (450 - 850 GWh per year), which in most cases allows the use an existing 220kV Alaverdi-Gardabani line. The only exception is the case with the possible construction of a new NPP with 1,000 MW capacity in Armenia, which given the long development and construction period can be considered unrealistic for the period under review.

Economic efficiency of such integration has been evaluated for Armenia on the basis of a comparison of options of integration with Georgia and the Armenian power system isolated operation. Electricity production costs for domestic consumers decrease depending on the price of gas for the considered power exchange and development of power generation capacity. See results of the analysis in the table below.

[12]Economic Efficiency of the Armenian Power System Integration and Analysis of Impacts of New Renewable Development in Armenia, 2012, Yerevan

Table 4.1 Integration Benefit to Armenia Due to Connecting with Georgia

Decrease in generation costs for electric consumers (million $)	
2015	
Gas price $180/mcm	11.4 – 21.2
Gas price $240/mcm	8.7 – 20.9
2020 with existing NPP	
Gas price $180/mcm	11.3 – 19.4
Gas price $240/mcm	18.0 – 27.9
2020 with existing NPP decommissioning	
Gas price $180/mcm	6.9 – 8.4
Gas price $240/mcm	16.8 – 24.5

As can be seen from this table, the optimal electricity exchange with Georgia allows Armenia to receive significant benefit even as prices of Russian gas at the border are increased.

In May 2013, Russia raised the price of gas for Armenia to $ 270/mcm.[13] In this regard appropriate adjustments were needed in the GTMAX Model. However, integration exchange volume and value were at about the same level.

Unfortunately, for Georgia, the GTMax Model was carried out with the generalized representation of the Georgian power system. However, it was assumed that the electricity exchange can be carried out only when it is beneficial for both sides of the trade. As a result, export prices (with differentiation by seasons and hours) from Georgia to Armenia were taken higher than the potential to Turkey, and the import price from Armenia to Georgia, such that they were required either domestically or on the Turkish market (re-export). Details are in the report cited in footnote 12.

Benefits of integrating Georgia and Armenia Systems

The main benefit for integration is that in isolated mode, Armenia is obliged to unload (to run at partial load) the existing NPP during 9 months of the year (essential in summer), then the generation price is about $25/MWh. This is due to the fact that usually in the power systems the generation of single unit can't exceed 60% of the system load (special automatic implementation in Armenia allowed to raise this percentage to 75%), but considering that the night load in summer is reduced to 380-400MW, and sometimes less, in that case NPP must be unloaded.

The second reason is the necessity to run Yerevan TPP to meet the peak load in summer. In Armenia, in summer, the ratio of maximum load to minimum load is very high - more than 2). At night, the TPP should work at least on a technical minimum (start-stop for a few hours is not practiced). This leads to a further NPP unloading, as it normally has to work with a constant capacity.

The integration of the two systems allows avoiding NPP unloading and using the low cost electricity from the NPP. First, integration allows Armenia to avoid the limitation of single unit capacity and second it is possible due to NPP's additional loading and a small import to shut down the expensive Yerevan TPP. Additional loading of NPP allows offering lower (competitive) prices for Armenian export.

[13] Armenia Public Service Regulation Commission

In addition, Armenian NPP decommissioning opens greater opportunities for Georgian export to Armenia.

CONCLUSIONS

Georgian and Armenian power systems integration would be expected to bring economic benefits to both sides.

A special study must be performed for determining economic flows between Georgia and Armenia taking into account current situation and seasonal demand and production levels in both countries.

4.1.2 Georgia – Armenia asynchronous operation

With today's situation, when Georgia is synchronized with Russia and Armenia with Iran, only the asynchronous operation between Armenian and Georgian power systems can be realized, due to the inability to synchronize power systems of Russia and Iran in the foreseeable future.

For asynchronous operation, a B2B construction is needed. In 2012, Fichtner carried out a pre-feasibility study of this issue, which considered various options for B2B and substation at voltages

1) 400/500kV, 1050MW (costs up € 360M); and,
2) 220 kV (250MW, costs € 72M) as the first stage of the project with subsequent extension.

To invest in such an expensive project, the expected ROI has to be taken into consideration, which is mainly determined by the electricity volumes through this new link.

Currently Armenia has two contracts with Iran:

- electricity for electricity exchange;
- electricity exchange on Iranian gas (3MWh is exchanged on 1000cm)

The first type of contract involves the electricity exchange by seasons taking into account that the peak load in Armenia is in the winter, while in Iran - in the summer.

It should be noted that the volumes on this type of contract have decreased from year to year, which can be seen from the Armenian import historical data (see Figure 4.2 below).

At the same time, the export volumes have sharply increased, which means the second type of contract preferential use.

Figure 4.1 Historical Armenian Imports

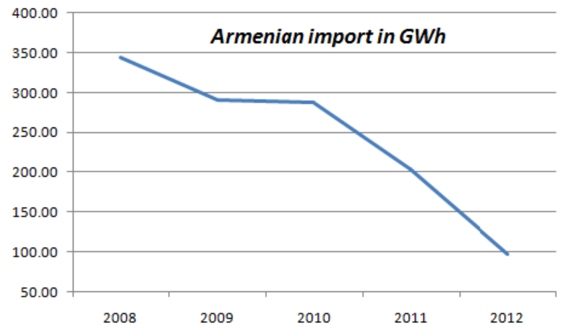
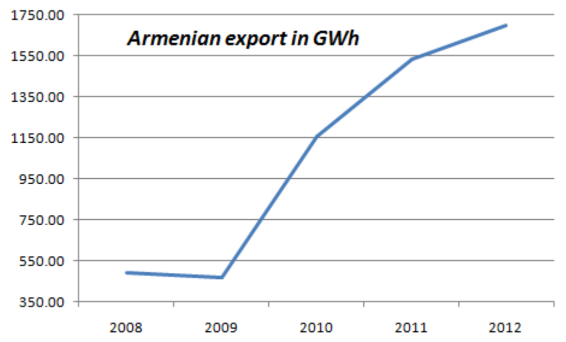


Figure 4.2 Historical Armenian Exports



The benefit of this type of contract for Armenia lies in the fact that the new units built in Armenia allow to generate more electricity burning natural gas than it must be deliver to Iran due to efficiency of these units (Yerevan TPP – 49%, unit #5 of Hrazdan TPP – up to 42%).In other words, the Yerevan TPP can generate up 25% on "free of charge natural gas" and unit #5 about 10%. Using old 200MW units of the Hrazdan TPP is inefficient in terms of this contract (low efficiency).

Under conditions of increased Russian natural gas price, it is clear that 100% of electricity generation on Iranian natural gas on the above two units is fully beneficial for Armenia. To ensure this, increased import of electricity from Georgia can be used. (see Table below).

Table 4.2 Armenian Surplus Energy and Gas Swap Potential

	Measurement unit	2013	2017	2022
Armenian domestic consumption	TWh	**5.9**	**6.5**	**7.4**
Net generation in Armenia, including	TWh	**8.9**	**9.0**	**9.1**
NPP	TWh	2.5	2.5	2.5
TPPs	TWh	4.2	4.2	4.2
HPPs	TWh	2.2	2.3	2.4
Armenian surplus	TWh	**3.0**	**2.5**	**1.7**
Conditions determination for Armenian TPPs functioning on “free of charge” gas				
Gas requirement for Armenian TPPs fully operation on Iranian gas	bcm	1.050	1.050	1.050
Gas received by contract, incl. losses (3%)	bcm	0.970	0.808	0.550
Required export to Iran (for Armenian TPPs fully operation on Iranian gas), incl. losses (3%)	TWh	**3.25**	**3.25**	**3.25**
Estimated required import from Georgia	TWh	**0.25**	**0.75**	**1.55**

The Iran-Armenia Contract "Electricity in Exchange for Natural Gas" is valid until 2027 and implies phased increase of traded volumes (see Table below). At the moment, there is a big difference between the contractual volumes and the actual deliveries from Armenia, which determines the potential export from Georgia to Armenia which can re-export it.

In this regard, there are opportunities for additional deliveries from Georgia.

Table 4.3 Armenian Potential Sales to Georgia Post Gas Swap Exports

Additional Georgian export opportunities				
Contract’s volume for flow to Iran from Armenia	TWh	4.5	5.0	6.9
Additional required flow to Iran, including losses (3%)	TWh	1.28	1.80	3.76
Total Georgian export potential estimation	**TWh**	**1.53**	**2.55**	**5.31**

Thus, the potential of electricity deliveries from Georgia to Armenia is sufficiently large to warrant exploring it further. However to realize this potential it is necessary to ensure benefits for both sides.

The benefit of Armenia can be achieved due to part of generation on TPPs on free-of charge-gas, ensuring Iranian gas in other sectors of the economy by prices that less than the replaced Russian gas, ensuring return on investment in the development of the transmission system. This can be achieved by appropriate import prices (see below).

Benefit of Georgia is the ensuring such prices for the electricity export that would be attractive to private investors in hydropower in Georgia.

An additional advantage for Georgian export in this direction compared with the Turkish is the possibility to deliver electricity regardless of the seasons and hours as well as in the Armenia-Iran gas for electricity exchange contract, only the respective volumes are considered. This is especially important bearing in mind that most of the near-term planned HPPs in Georgia are run-of-river.

Let us consider possible prices that satisfy both sides.

As a criterion of marginal price the condition that the equivalent price of Iranian gas to Armenia should be lower than the Russian will choose.

In this case we have

$$Tm_{arm\text{-}iran} = Pgas_{rus} * (1\text{-}L\%/100) / Ke \qquad (1)$$

Where $Pgas_{rus}$ *– gas price on Russia-Armenia border;*
$Tm_{arm\text{-}iran}$*- marginal price on Armenia-Iran border;*
L% -electricity losses percentage in Armenian transmission system;
Ke – electricity / gas exchange ratio according Armenia-Iran contract

The marginal price on Armenia-Georgia border can be estimated by the formula

$$T_{GEOm} = Tm_{arm\text{-}iran} – T_{B2B} – T_{TR} \qquad (2)$$

$$T_{B2B}=Costs_{B2B} / E \qquad (3)$$

Where: T_{GEOm} *– marginal price on Georgia-Armenia border;*
T_{B2B} *– ‘price component due to B2B link;*
$Costs_{B2B}$ *– annual costs of B2B link;*
E – annual flow through B2B;
T_{TR} *– transmission tariff in Armenia, including new 400kV line to Iran or transit tariff*

Even if this was a reasonable methodology for estimating the value of construction of B2B facilities on the existing 220kV line with 250MW capacity, Georgia over the next few years will not have such a surplus to provide supplies for which it would create a restriction of transfer capability on existing 220kV line.

In any case, the Armenian side has already decided that if the construction will be realized, it will be implemented by stages (it is assumed that B2B facilities will be built on the territory of Armenia close to border in Ayrum).

With 3% losses and Ke = 3 with the Russian natural gas price $270/mcm for Armenia, the marginal price at the border of Armenia-Iran would be $87.3/MWh.

To evaluate the possible Georgian export prices for this report, the level of 2017 will is assumed. This is a preliminary estimation; the actual calculations can be carried out later in the refinement the original data.

After the Fichtner's pre-feasibility study, the annual costs necessary to recover the investment has been evaluated as $8.5 million by TetraTech within the above-mentioned project. Even if we assume that these costs will be covered only by the Georgian exporters (export volume 750 GWh), T_{B2B} = $11.4/MWh.

Current transmission tariff for domestic consumers in Armenia is about $1.5/MWh.

Iran is funding the new line of 400kV Armenia-Iran on favorable terms of return on investment. Further analysis should be made after verification of the original data given the expected significant volumes of flows (more than 3,000 GWh per year. The estimated component of the tariff will not exceed $4.5/MWh (high probability of a lower value).

Even if to add the “cost-of-doing-business” of the Armenian side of about $5-10/MWh, the price for Georgian exporters on Georgia-Armenia border will be $60-65/MWh and possibly higher, which is an attractive price for the Georgian traders (e.g., a Consolidator) and investors in hydropower in Georgia.

CONCLUSIONS

Electricity supply to Armenia is much more attractive for Georgia in terms of volumes and prices in the case with electricity flow from Armenia to Iran compared with the case when Armenia is disconnected from Iran.

In the case when Georgia's electricity network is disconnected from Russia, it isn't necessary to build B2B facilities and the potential price of electricity supplies to Armenia will be higher (at least $70/MWh).

Considering the relatively big volumes, high delivery prices, the possibility of operation with a flat delivery schedule and the lack of seasonal restrictions may turn out that the Armenian direction of Georgian export will be is even preferable than Turkish.

4.2 Possible trade between Azerbaijan and Georgia and through its territory with Turkey

The current electricity trade between Azerbaijan and Georgia is characterized by small daily exchange volumes (maximal flow is 50MW).

At first glance, quite a large-scale construction of new power plants in Azerbaijan may significantly change the situation. The commissioning of "Janub" TPP (780 MW) and a second unit, "Shimal" TPP (409 MW) with an efficiency of about 52% is expected in the near future.

Electricity deliveries from Azerbaijan are possible:

- For the Georgian domestic needs (in winter);

- As export to Turkey (transit through Georgia).

In recent years, the second option became a priority for Azerbaijan. USAID's Power Bridge Azerbaijan-Georgia-Turkey was created. For this purpose, a new 500 kV line Azerbaijan TPP – Gardabani will put into operation soon.

4.2.1 Deliveries to Turkey

For the electricity export from Azerbaijan to Turkey, competitive prices must be ensured. It is necessary to take into account that Azerbaijan exports gas to Turkey too via the Baku-Tbilisi-Erzurum pipeline by price $260-280/mcm and its capacity will be increased to 20bcm per year, and to 45 BCM per year in future.

Thus, a reasonable question arises. What is more profitable to export, gas or electricity?

Unfortunately, not all pricing parameters are available on export of gas so some assumptions are made for this report. Assuming that the gas transit fee through Georgia is 10%, the minimum price of gas at the Azerbaijan-Georgia border would be $234/mcm.

What is electricity price may be offered to the Turkish market by burning gas in Azerbaijan at the price of $ 234/mcm?

Two options will be considered:

1. Export is carried out only from new combined-cycle TPPs;
2. Export is carried out both by new and old TPPs

Option 1 for Azerbaijan selling to Turkey

New TPPs (efficiency - 52%) will provide 4.7 MWh/mcm. Thus the price of just the fuel component with the minimum losses for electricity transfer to Turkey (3%) would be $51.4/MWh.

To estimate the remaining costs we use the data prepared by US Energy Information Administration and shown in Table 4.4 below.

Table 4.4 Estimated Levelized Cost of New Generation Resources

Table Estimated Levelized Cost of New Generation Resources, 2016.

Plant Type	Capacity Factor (%)	U.S. Average Levelized Costs (2009 $/megawatthour) for Plants Entering Service in 2016				
		Levelized Capital Cost	Fixed O&M	Variable O&M (including fuel)	Transmission Investment	Total System Levelized Cost
Conventional Coal	85	65.3	3.9	24.3	1.2	94.8
Advanced Coal	85	74.6	7.9	25.7	1.2	109.4
Advanced Coal with CCS	85	92.7	9.2	33.1	1.2	136.2
Natural Gas-fired						
Conventional Combined Cycle	87	17.5	1.9	45.6	1.2	66.1
Advanced Combined Cycle	87	17.9	1.9	42.1	1.2	63.1
Advanced CC with CCS	87	34.6	3.9	49.6	1.2	89.3
Conventional Combustion Turbine	30	45.8	3.7	71.5	3.5	124.5
Advanced Combustion Turbine	30	31.6	5.5	62.9	3.5	103.5
Advanced Nuclear	90	90.1	11.1	11.7	1.0	113.9
Wind	34	83.9	9.6	0.0	3.5	97.0
Wind – Offshore	34	209.3	28.1	0.0	5.9	243.2
Solar PV[1]	25	194.6	12.1	0.0	4.0	210.7
Solar Thermal	18	259.4	46.6	0.0	5.8	311.8
Geothermal	92	79.3	11.9	9.5	1.0	101.7
Biomass	83	55.3	13.7	42.3	1.3	112.5
Hydro	52	74.5	3.8	6.3	1.9	86.4

As can be seen from this table above, the amount of non-fuel costs (levelized capital costs, fixed O&M and transmission investment) for a combined cycle TPP will be at least $20/MWh.

Considering that for electricity export to Turkey and improve power system reliability, Georgia is implementing a very ambitious project (loan is about 300 million euro).

Georgia is likely to be able to achieve a relatively small transit tariff - $5-10/MWh from Azerbaijan. Of course, the advantageous price for Georgia is much higher, but it can lead to a sharp decrease of transit volume and Georgia will not gain anything.

The current legislation in Turkey allows to companies registered in Turkey only to operate on its electricity market. These companies buying Azerbaijan electricity will be forced to take all risks. Assuming that the "cost-of-doing-business" of these companies is $5-10/MWh and the transmission costs within Azerbaijan must be added taking into consideration the investment in the new 500 kV line, the average price of Azeri electricity on Turkish market would be $ 85-90/MWh for the first option.

Option 2 for Azerbaijan selling to Turkey

At present, the average fuel consumption per kWh (ex-Soviet standard) in Azerbaijan is 313.2 g/kWh (Azerenerji data). This is equivalent to average generation 3.65 MWh/mcm. Assuming that the new TPPs are put into operation, the average consumption will increase to 3.8 MWh/mcm.

The fuel component (with losses) will in Option 2 increase up to $63.5/MW, and levelized capital costs will decrease, fixed O&M costs would increase significantly versus Option 1, which leads to final price increase in comparison with Option 1. With such an annual average price, regarding these new units being competitive, it will be hard, even in peak season (August).

In general it would be price-competitive to sell electricity on-peak from Azerbaijan to Turkey, taking into account the flexibility of a combined-cycle TPPs. However, the price will increase due to reducing the export volumes (in the table above the costs appropriates to capacity factor equal to 87%).

Considering that the export is carried out from TPPs it's evident that constant deliveries are more beneficial. But for this it is necessary to reduce the offered prices. This may be achieved only by reducing the price of used gas.

An estimate of the internal subsidy of gas price is 20% and more. This means that for Azerbaijan, gas export to Turkey is more profitable than producing electricity for export sales. Taking into account that the State is Azerbaijan's energy sector majority owner, subsidies of natural gas for generation production are likely to continue. This means that the intended electricity export to Turkey is determined more by political considerations than economic.

Apparently this explains the agreement reached between Azerbaijan and Turkey in May 2012 about a relatively small volume of export (750GWh per year) compared with expected at the beginning of the project AGT power bridge (2-3TWh per year).

In a possible future the large impact on export to Turkey (by way of limitation) will be the policy of Russia in Turkish direction and the process of new power plants construction in Georgia.

4.2.2 Deliveries to Georgia

Delay of the construction of new power plants in Georgia leads to import increase. At present, the main supplier of electricity to Georgia in winter is Russia. According to the ESCO the import price is $ 60-65/MWh.

There is an opportunity for imports to Georgia from Russia and this price will most likely grow. In this connection in 2012, Georgia signed an agreement with Armenia about so-called "emergency supplies", which are determined not only by faults in power systems, but also in terms of long-term supply. Price in the contract was set at $66/MWh. These prices are quite competitive compared with Turkish market prices considering that the electricity supply for domestic needs of Georgia does not need to take into account the "cost-of-doing-business" of the Turkish partner and the cost of transit fees.

In addition, it is possible to supply better load following in Georgia, considering the opportunity to apply the daily regulation in Georgia due to the water accumulation at night on large hydropower plants and its drawdown during peak hours.

It is also necessary to take into account the fact that the peak consumption in Turkey is in summer, and in Georgia is in winter, which gives an additional export possibility to Azerbaijan depending on the season and the needs of each country.

4.3 Electricity trade between Georgia and Russia

Electricity trade between Georgia and Russia over the last years was a seasonal power exchange (Georgia exported in summer and imported in winter).

What conclusions can be made about the prospects of trade on the basis of historical data?

Export / import volumes

Table 4.5 below shows the annual volume of export / import with neighboring countries as well as only with Russia.

Table 4.5 Comparison of Total Georgian Exports to Exports to Russia

Years	Total export (GWh)	Total import (GWh)	Total net export (GWh)	Export to Russia (GWh)	Import from Russia (GWh)	Net export to Russia (GWh)
2007	625	433	192	306	177	129
2008	680	649	31	435	561	-126
2009	749	255	494	526	154	372
2010	1524	222	1302	1073	205	868
2011	931	471	460	460	446	14
2012	528	615	-87	369	517	-148

As can be observed from the table in 2012 for the first time since 2007, Georgia has a negative trade balance (deficit with Russia in 2008 is explained by war). This is explained by the increase of domestic consumption and the lack of implementing new generating capacities. Peak export of Georgia was in 2010 (high water year).

The monthly historical data of trade between Georgia and Russia should be considered, which are listed below.

The first thing to note is the significant increase of import from Russia in winter (October - March).Taking into account that according to the ESCO average purchase price of this electricity for domestic consumption is currently $60-65/MWh, the benefit of substitution of the import by the construction of new power plants in Georgia is evident.

On the export side, the implementation of a new 400kV connection to Turkey with attractive prices for Georgian exporters implies that exports to Russia will be decreased.

An interesting fact should be noted. Turkish power system peak load, unlike Georgia and Russia, is in the summer (August). Georgian export potential maximum can be realized over a period of five months (April-August) and is declining in volumes. In July and August the Turkish direction is favorable. However, given that in Turkey there is enough water during April-June, which means more production at its own power plants, the maximum flow of Georgia (including supplies from neighboring countries) is limited by 350MW. Because of this, the Russian direction can also be interesting in case of significant constructions of new HPPs in Georgia.

Table 4.6 Import/Export Trade with Russia (2007-2012)

Ge-Ru (export)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
2007	0	0	0	0	0	8	143	123	7	10	3	12	**306**
2008	2	2	32	148	53	0	7	103	34	44	9	1	**435**
2009	0	28	1	0	82	121	178	100	1	12	0	3	**526**
2010	0	0	59	195	248	209	211	95	0	30	21	5	**1073**
2011	0	0	0	0	15	232	134	54	11	9	5	0	**460**
2012	0	0	0	0	76	188	82	18	4	0	1	0	**369**
Ru-Ge (import)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Year**
2007	0	0	0	0	0	0	0	4	2	40	65	66	**177**
2008	121	138	79	53	0	0	0	48	24	3	18	77	**561**
2009	0	25	0	1	4	0	3	3	3	0	43	72	**154**
2010	11	0	14	0	1	2	2	1	0	44	62	68	**205**

2011	77	78	22	2	0	0	7	2	16	6	97	139	**446**
2012	80	74	125	22	0	0	1	0	22	51	48	94	**517**
Ge net export	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Year**
2007	0	0	0	0	0	8	143	119	5	-30	-62	-54	**129**
2008	119	136	-47	95	53	0	7	55	10	41	-9	-76	**-126**
2009	0	3	1	-1	78	121	175	97	-2	12	-43	-69	**372**
2010	-11	0	45	195	247	207	209	94	0	-14	-41	-63	**868**
2011	-77	-78	-22	-2	15	232	127	52	-5	3	-92	139	**14**
2012	-80	-74	125	-22	76	188	81	18	-18	-51	-47	-94	**-148**

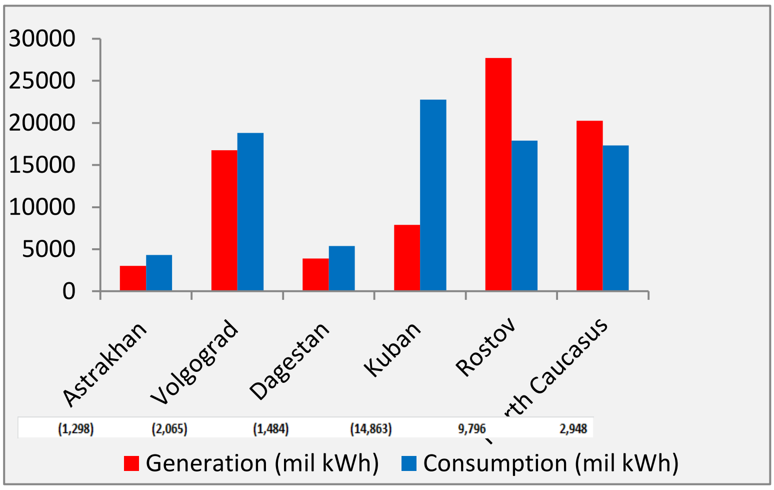
It's necessary to make a detailed study of possible supply prices to Russia. Currently, such supplies are made for two reasons:

- There is no serious alternative;
- Existing Georgian HPPs produce low price electricity.

It's necessary to provide much higher export prices; however, they may be limited by internal factors in Russia. For example, today the wholesale prices in the North Caucasus are not determined by the market and are determined as $30-40/MWh due to subsidies, though calculations of market prices are carried out. These costs, of course, are not interesting for investors in the Georgian hydropower.

The analysis of the balance of electricity in the North Caucasus in 2012 (see Figure 4.3 below) shows that on annual basis only Dagestan has deficit, the rest of the republics of the North Caucasus have a surplus more than the deficit of Dagestan.

Figure 4.3 Generation and Demand in Southern Russia Region



As can be seen from this Figure 4.3 the largest deficit in the South of Russia is observed in the Kuban (Sochi region). Currently, due to upcoming 2014 Olympic Games, the covering of this deficit is provided by the other regional power systems of Russia, for which large construction of transmission lines was undertaken.

In terms of new generation sources, in January 2013 360 MW Adler combined cycle TPP was introduced. For the 367 MW gas turbine Kudepsta, permission was received in April 2013, but there is serious resistance from environmentalists.

It should be noted that even with decision to reduce consumption for the Olympic Games from 1380 MW to 850 MW in May 2013, this region will remain deficient in terms of electricity.

In this case, there are certain obstacles for Georgian export to Russia. Units #3 and #4 in Rostov (Volgodonsk) NPP with a capacity of 1,000 MW each are currently under construction. Even if their launch will be delayed (unit #3 is scheduled in 2015 and #4 in 2017), it is unlikely that at this time Georgia will introduce significant capacities on the new power plants before completion of the NPP construction.

Besides, considering that although these units require a return on investment, and like all new NPPs the price of electricity should be high enough, in reality, they have the advantage of being part of the "Rosenergoatom" that integrates all Russian nuclear power plants. Therefore they can offer relatively low price (currently on domestic market the electricity price for Russian NPPs is about $40/MWh). This price is much lower than required for new power plants in Georgia.

In this regard, Russia may have an interest in electricity export to Turkey through Georgia (not until appearance of the new units). However, Russian policy is somewhat different at present time. Russia invests in Turkey in the construction of 4800 MW NPP, also purchased Khrami1 and Khrami 2 HPPs in Georgia and plans to build another one (about 100 MW).

The analysis of historical data of Georgian export and import daily shapes is also interesting. For example, the night electricity export level is much less than in peak hours, while imports at the night are not less than the peak levels. Night time imports allow the saving of water at night on regulated power plants in Georgia. In addition, at the end of the 1990s, the electricity pricing between Russia and Georgia assumed considerably low price at night in comparison with peak (perhaps a similar system is used now).

Figure 4.4 Export from Georgia to Russia

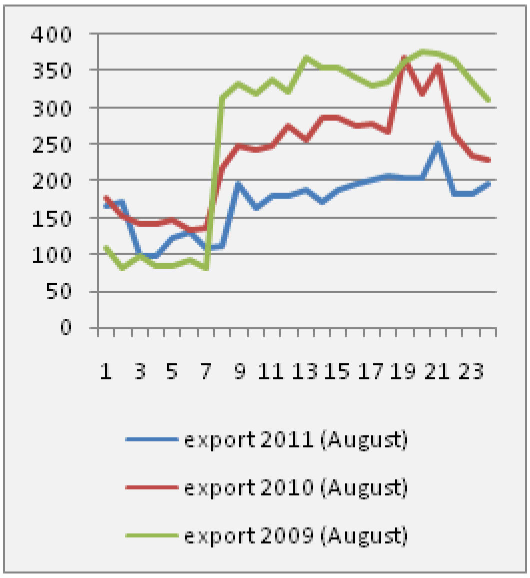
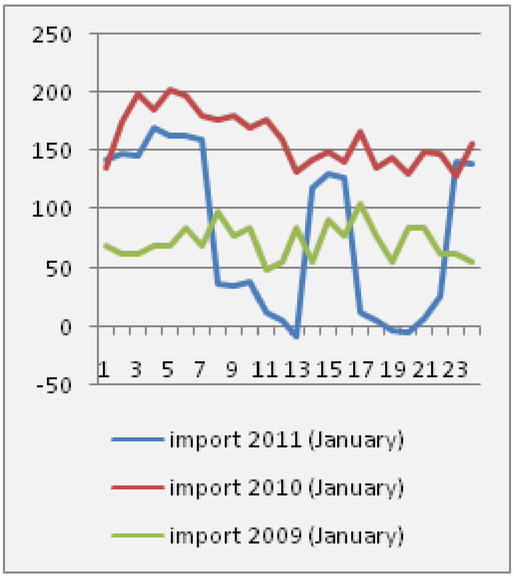


Figure 4.5 Import from Russia



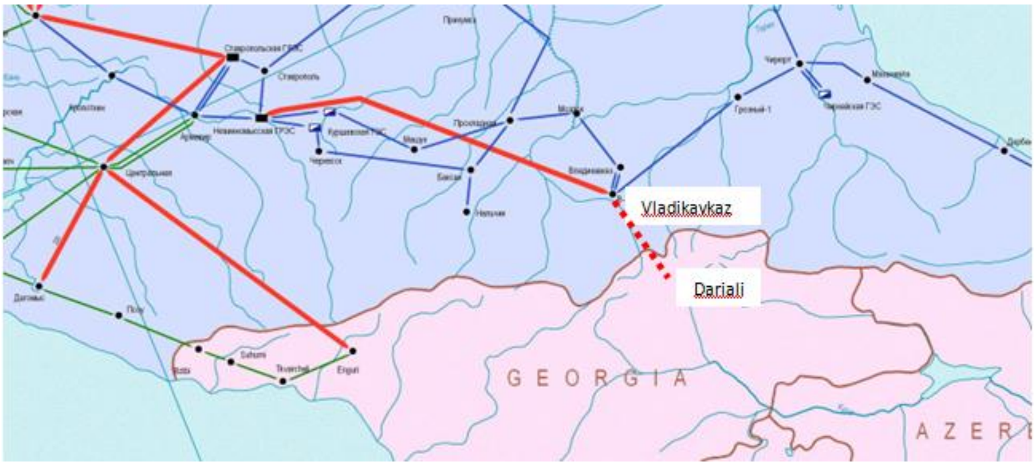
Network development

Georgia is now connected to Russia by 500kV line, Kavkasioni, 220kV line, Salkhino (through Abkhazia), and two 110kV lines, Dariali and Java. The last two lines can be used in island mode (transfer capacity up to 30 MW).

The 500 and 220 kV lines have a transfer capacity much more than the possible flows (even in a peak 2010 year the flow by Kavkasioni did not exceed 500 MW).

The possible new line construction is mainly due to the construction of 109 MW Dariali HPP. The construction of a 500 kV line Dariali–Vladikavkaz (only one 500 kV substation in this region of Russia, see Figure 4.6 below) has even been discussed. The length of this line could be 40-50km. However, it will be necessary to build the 500kV substation at Dariali plant that would lead to the impossibility of return on investment. The extension of this line to Ksani is additional 150km. Initially this project is not effective taking into account also that there is no deficit in Vladikavkaz region.

Figure 4.6 Southern Russian Region High Voltage System



The same conclusion may be reached by considering the 330kV option.

The most probable is the option with 220kV line construction to Ksani which will cover the growing domestic load in Georgia, as well as to participate in the export to Turkey.

Conclusions

In the coming years the volume of Georgian electricity exports to Russia will be significantly reduced, because of internal load growth in Georgia.

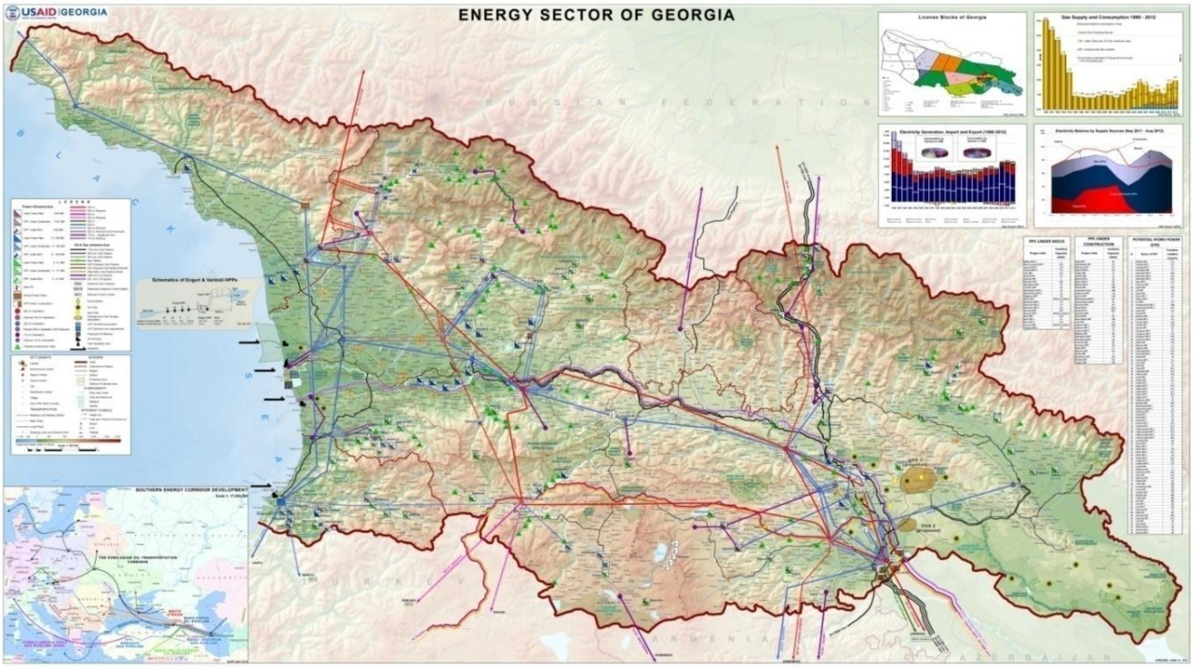
New HPPs in Gerogia can replace expensive existing TPP or relatively expensive Russian imports. Georgian export to Russia is less effective than to other neighboring countries for new HPPs in Georgia in summer time. The transfer capacities of the existing lines between Russia and Georgia are sufficient enough for possible exchanges until 2018-2020 and perhaps longer.

4.4 Georgia –Turkey Potential Trade

There are many studies regarding Georgian export to Turkey. For this purpose known large-scale network construction is nearing completion:

- SS 500/400/220 kV Akhaltsikhe with B2B converter 2x350 MW;
- 500 kV lines Gardabani-Akhaltsikhe and Zestaponi-Akhaltsikhe;
- 400 kV line Akhaltsikhe-Borchka (Turkey)

Figure 4.7 USAID Energy Map of Georgia



In all these studies, significant electricity export (including transit) to Turkey was considered as an incentive for investors in hydropower in Georgia. In all cases only positive factors, such as high prices for the Turkish market was considered. The extension of capacity of B2B to 1050 MW was envisaged.

However, there are several constraints to export and construction of new power plants in Georgia both.

In none of studies was an integrated analysis of the task, namely, the transmission and generation activities taking place in Turkey were not considered.

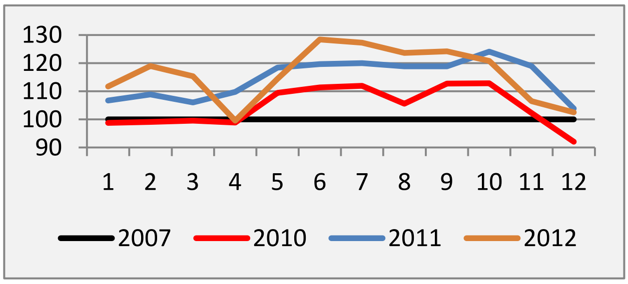
This study deals with the analysis of the problems and the possibilities of trade between Georgia and Turkey determination taking into account the current realities.

4.4.1 Consumption growth in Georgia and export potential

The domestic consumption growth has great impact on export potential in Georgia. So, in 2012, for the first time since 2007, Georgia has become a net importer instead of net exporter.

The load growth by month in relation to 2007 is shown on Figure below (data for 2008 and 2009 are unrepresentative due to war and crisis), where rapid growth of summer load (export season) in relation to winter load (import season) is visible. Here and later used historical data are the data from ESCO's website.

Figure 4.8 Load growth by months in % to 2007



As can be seen from the following figure, potentially Georgian export is possible from April to August.

There is decreasing export potential to the extent there would be high load growth and delay in commissioning new hydropower plants.

Figure 4.9 Georgian net export by months in GWh

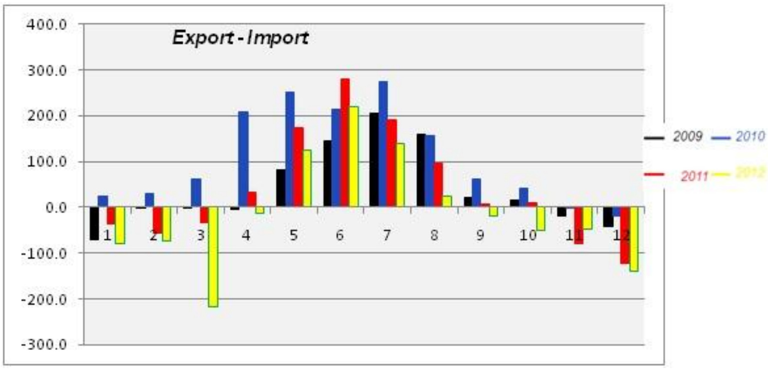
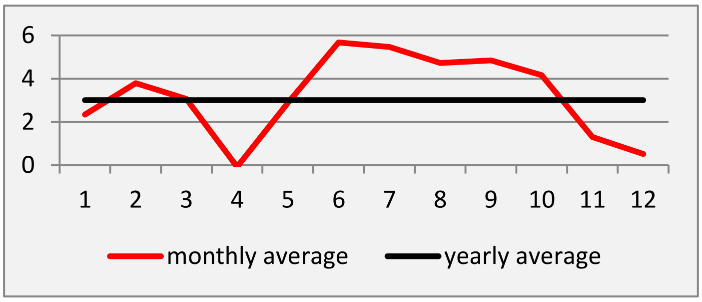


Table 4.7 Georgian Summer Hydropower Generation (2010-2012)

	Hydro generation in Georgia					GWh
	April	May	June	July	August	5 month
2010	922	927	844	957	811	**4461**
2011	638	894	963	922	832	**4249**
2012	603	825	947	909	718	**4002**
Average	*721*	*882*	*918*	*929*	*787*	*4237*

Load growth average annual percentage (2007-2012) amounted to 3%, although the summer percentage is growing more than winter (see Fig.).

Figure 4.10 Load growth average percentage by months



At such growth after 2015 in Georgia the export potential from existing HPPs will be close to zero.

Table 4.8 Georgia Export Potential Based on Historical Monthly Growth

	April	May	June	July	August	5 month
Export potential with historical montly load growth in % - 2013	25	187	175	139	11	**537**
Export potential with historical montly load growth in % -2015	26	147	89	50	-64	**248**

Even if the average annual percentage growth is assumed for the summer months, by 2017 export period is narrowed up to three months and export volume does not exceed 260 GWh per year.

Table 4.9 Georgia Export Potential Based on Historical Annual Growth

	April	May	June	July	August	5 month
Export potential with historical average annual load growth (3%) - 2013	3	186	194	157	24	**565**
Export potential with historical average annual load growth (3%) - 2017	-87	99	103	60	-73	**103**

It is necessary to note one important fact. Georgia operates in parallel with Russia and exports summer electricity there. This synchronous operation allows Georgia to improve the reliability of the power system significantly. Furthermore, the frequency control of the Georgian is facilitated by the Russian power system.

For this case, the minimum flow through 500 kV Kavkasioni line is defined somewhere between 30-50MW and if Russia will not export to Turkey (see section 3.3) and if Georgia is completely reoriented to Turkey, then this line would likely be disconnected.

Thus, the possible Georgian export to Turkey may be reduced by the volume of deliveries to Russia.

Georgian export and Azerbaijani transit volumes show that currently the construction of any new power plant in Georgia will not be limited by the possibility of supply to Turkey even during "restrictive" period from April to June (restriction is 350 MW due to high water season in Turkey).

4.4.2 Factors in Turkey affecting on the Georgian export

These factors can be divided into two groups: technical constraints and price parameters.

Network constraints

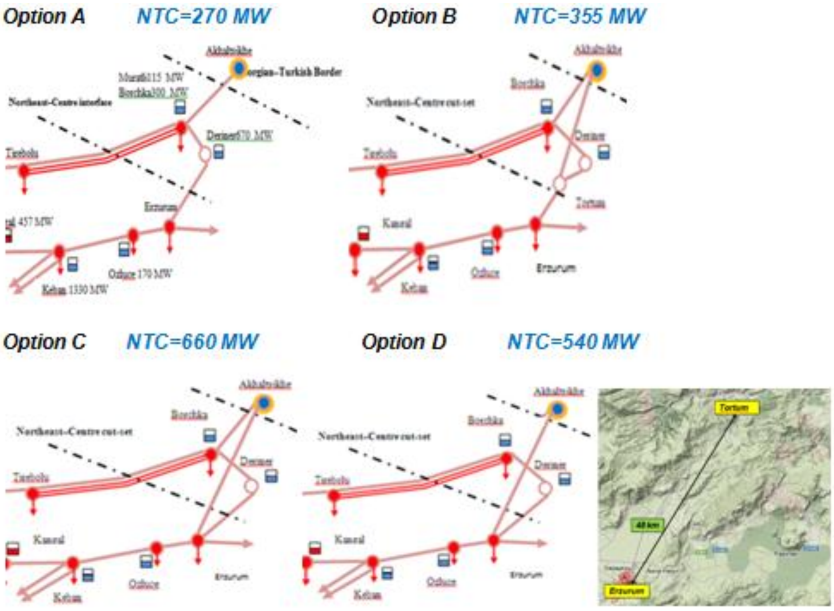
In Turkey, the main load falls on the central and especially western parts, while the eastern part (connection point with Georgia) has low consumption. At the same time in this part of Turkey's the huge construction of HPPs is planned (about 6000MW). Currently, Muratli (115MW) and Borcka (300 MW) are working, Deriner (670MW) is under construction, Yusufeli (540MW) and Artvin (332MW) are scheduled for construction. So far, the flow is directed from the center to the east, however, the situation will change with Deriner commissioning and import from Georgia.

In this regard, the estimated calculations for transfer capabilities of East-Center interface were performed. This interface transfer capability primarily will affect Georgian electricity export. This interface consists of lines Deriner-Erzurum (400kV) and 400 kV and two 154 kV lines Borchka-Tirebolu (see Option A on Figure 4.11 below).

During normal operation planned in the first years, electricity flow from Georgia (650 MW) can be provided. However, according to EU requirements, Net Transfer Capacity is determined whenever at least one line is tripped. So the weak point of this interface is the 400kV line Deriner-Erzurum. When disabling the line (repair or fault), the flow from Georgia will be limited to 270 MW in case when Turkish HPPs are fully loaded.

The Turkish HPPs unloading in these regimes can be carried out only when the possibility of water accumulation in the reservoirs and regime profitability exist. Otherwise, Georgian electricity export will be limited.

Figure 4.11 Options for the New Transmission Connection to Turkey



In case of line disconnection, it is possible Akhaltsikhe-Borcka line also will disconnected (by automatic control). At the same time, in case with large power flow to Turkey, the Georgian power system forms a large capacity surplus and, in this sense, connection with Russia is very important. Otherwise, Azerbaijan-Georgia link must be tripped immediately to help only in the case with a relatively large flow from Azerbaijan in pre-fault regime.

Akhaltsikhe-Borcka line disconnection also leads to the same consequences for Georgia. In this case, it is necessary either to use phased segregated tripping (most short-circuits are single-phase) or consider the possibility of building a second line from Georgia to Turkey.

At present time, the construction of the new 400kV line Akhaltsikhe-Tortem is planned. However, calculations show that this new construction will only increase the NTC on the Turkey-Georgia interface 355 MW (all calculations are in accordance with EU requirements) and hardly an economical solution (Option B).

A significant NTC increase can be achieved by construction Akhaltsikhe-Erzurum line instead of Akhaltsikhe-Tortum (Option C). This will ensure the Georgian export independence from Turkish HPPs regimes. An extended Georgian export line that includes Tortum to Erzurum in “Georgian export scheme” will increase the NTC to 660 MW. The route, in a straight line, it is only 48 km.

To conserve costs, the option of changing the 400kV line point of connection from Borcka to Erzurum could be considered (Option D).This would increase NTC to 540 MW (only 120 MW less than under Option C). In this case with only one export line existing, it would be necessary to use the phased segregated tripping.

The development plans of Turkish power system shows the construction of a new 400kV Borcka-Keban line. This construction will go in parallel with the construction of new Yusufeli and Artvin HPPs. Therefore, the Borcka to Kepan line will not remove the above-mentioned restrictions on Georgian export.

Prices

Under current Turkish legislation, only registered companies in Turkey can participate on the wholesale market. This means that export from Georgia will go through an intermediary with its «costs of business». These costs can be quite large, given that the partner takes all risks associated with selling Georgian electricity on the Turkish market.

These risks primarily include:

- Big difference in prices at the night and at the peak on Turkish market taking into account that mostly new Georgian HPPs are “run of river”;
- The need to consider congestion management problem on Turkish market.

Turkish traders will desire to maximize profit with risk management can lead to significant differences between average prices on Turkish market and for Georgian electricity on border.

Compared to existing HPPs, the new HPP plants in Georgia will produce relatively expensive electricity (the need for return on investment) and in this regard the flow increase can be expected only when the difference between generation costs including transmission and possible prices on border is positive.

In this regard the transmission tariff for exporters is very important. The initial estimation (separate study) shows that in the first few years in Georgia an export tariff based on «Use of Cross Border Facilities» methodology cannot be implemented because even when only costs for B2B and the new line to Turkey are taken into account, the value is significant (more $20/MWh when Azerbaijan uses transit tariff of $5-10/MWh) which will be a barrier for investors in hydropower.

It should be noted that all additional financial burden of the new network construction not considered export facilities will be on the domestic consumers.

4.4.3 Georgian import from Turkey in winter

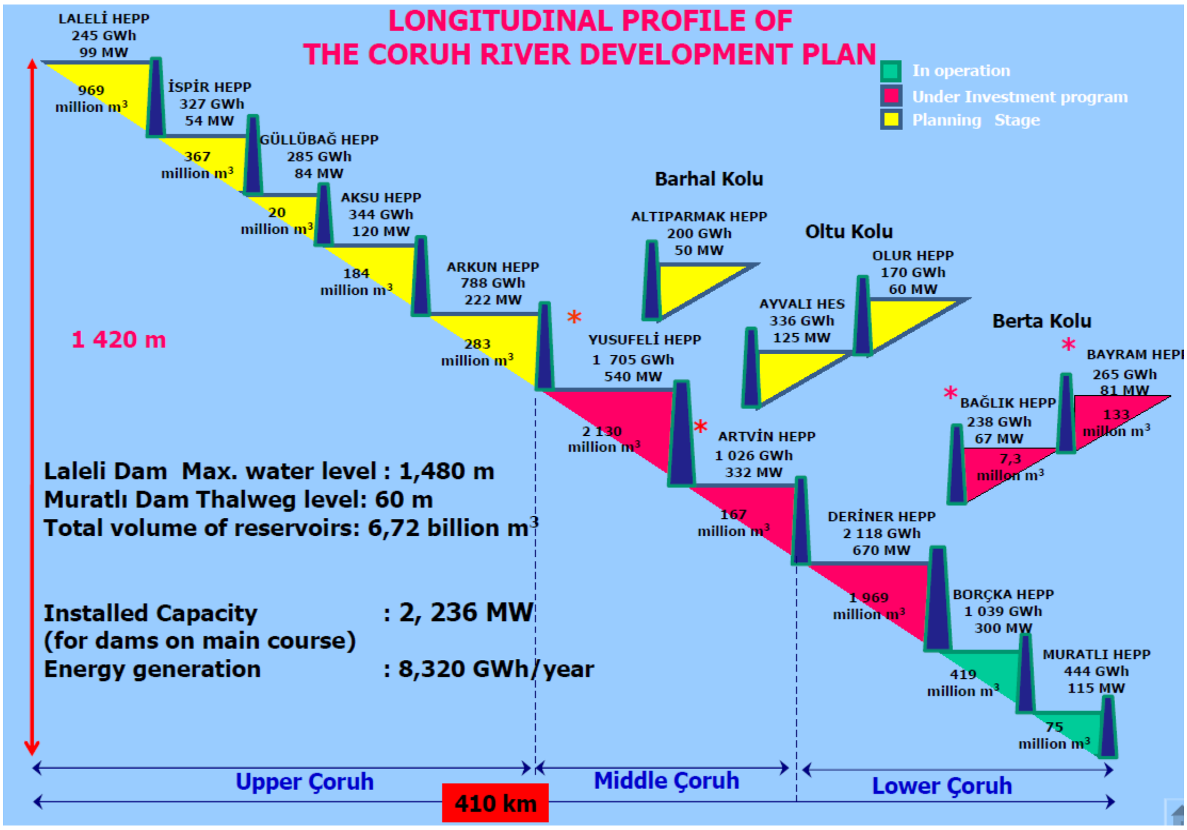
During most months of the year, Georgia has imported electricity and electricity import still continues to grow. In fact, the monopolist of electricity import is Russia, and prices have already reached $60-65/MWh.

The construction of large hydroelectric power stations in eastern Turkey with big reservoirs with annual regulation, with a practically ready network infrastructure to Tbilisi makes it very probable the electricity supply in the winter to Georgia from Turkey instead of Russian deliveries or for old Georgian TPPs’ generation replacement.

Figure 4.12 below presents data on plans to build new power plants on the Coruh River (presentation[14] in Tbilisi in 2009).

[14]Coruh River Development Plan. UbeydSezer, International Workshop on Transboundary Water Resources Management. Tbilisi, 2009.

Figure 4.12 Coruh River HPP Cascade Development Plan



In Turkey, the peak load typically occurs in August. The winter load and, therefore, the market price, is lower. Sufficiently attractive prices on the Georgian market can give Turkey advantages over Russia for supply of electricity to Georgia, taking into account practically no transmission costs.

The Georgian benefit is evident - import price decrease or at least dampen with competition to electricity imports from Russia.

USAID Hydropower Investment Promotion Project (USAID-HIPP)

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